Appendix 3-C

Transmission Issues for Offshore Wind Farms

APPENDIX 3-C

TRANSMISSION ISSUES FOR OFFSHORE WIND FARMS WITH SPECIFIC APPLICATION TO SITING OF THE PROPOSED CAPE WIND PROJECT

Note to the reader: This document is an edited revision of a paper entitled "Limitations of Long Transmission Cables for Offshore Wind Farms" Copyright 2003 produced by ESS, Inc., consultants to Cape Wind Associates, LLC.

1.0 EXECUTIVE SUMMARY

The current method for interconnecting offshore wind generation farms with onshore utility transmission systems is through alternating current (AC) submarine cable systems, based upon existing facilities, all of which are located in Europe. One offshore wind project, Horns Rev in Denmark, is using a high voltage AC (HVAC) transmission system to bring power to shore. As the distance between the wind farm and the onshore interconnection increases, the limitations of HVAC cable technology emerge. This paper discusses those limitations and compares high voltage direct current (HVDC) to HVAC along with a discussion of the present state-of-the-art of HVDC cable systems, and advantages and limitations of HVDC for application to offshore wind farms. This is not a simple comparison, as variables include line losses, cable costs, transmission voltage, distance, charging current, power conditioning, and costs of converter stations. Transmission lines need to be energized, and unlike submarine cables between power grids, offshore wind farms have unique characteristics, such as variable power output. While both AC and DC are viable transmission technologies, HVDC is not yet commercially proven for offshore wind farms, and may be more cost effective for far offshore (greater than 50-100km (31- 62 mi)) applications once available.

2.0 INTRODUCTION

Electric energy generated by offshore wind generating facilities requires one or more submarine cables to transmit the power generated to the onshore utility grid that services the end-users of this renewable energy source. Because the power from the wind turbines is generated as an alternating current (AC) and the on-shore transmission grid is AC, the most straightforward technical approach is to use an AC cable system connection to facilitate this interconnection. Present state-of-the-art[1] and the most cost effective AC technology for this type of interconnection is solid dielectric (also called extruded dielectric or polymeric insulated) cable, usually with cross-linked polyethylene (XLPE) insulation. This is the cable system technology presently used for all offshore wind farms constructed to date (all of which are located in Europe) primarily as a result of: ease of interconnection, installation, and maintenance; operational reliability; and cost effectiveness.

For relatively small generating capacity wind farms it has been sufficient to bring the power to shore at the same voltage used to interconnect the wind turbine generators (WTG), typically 33 kilovolt (kV). As the energy generating capacity of the wind farm increases, however, use of submarine cables in this voltage class for the connection to shore would require a prohibitively large number of cables and would lead to high line losses and excessive voltage drops combined with unnecessary sea-bed disturbance to accommodate installation of many cables. One solution is to step up the wind farm transmission voltage from the WTG production and collection voltage of 33 kV to a higher AC voltage suitable for transmission to shore. This requires an offshore substation platform containing step-up transformers. The first wind farm large enough to require this approach is the 160 MW Horns Rev Wind Farm commissioned for operation in December 2002 in Denmark.

3.0 PROPOSED TRANSMISSION SYSTEM – SOLID DIELECTRIC HVAC

The 420 MW Cape Wind Project proposes an electric transmission interconnection similar to Horns Rev: the WTG's within the wind farm grid will be interconnected at 33 kV AC to an offshore substation located within the WTG grid. The lower voltage cable systems will deliver power to the substation platform where it will be transformed (or stepped-up) to 115 kV AC for transmission to shore. The 115 kV voltage for the Cape Wind Project was chosen to match the voltage of the existing NSTAR Electric overland utility transmission lines (115

[1]Wright, S.D., Rogers, A.L., Manwell, J.F., Ellis, A., "Transmission Options for Offshore Wind Farms in the United States," AWEA, 2002, p. 2.

kV) to which the project will be interconnected, thereby avoiding the need for a second voltage transformation on shore.

The proposed 115 kV submarine cable interconnection between Cape Wind's offshore substation and landfall would utilize four (4) three-conductor XLPE insulated cables, each with 800 mm^2 (approx. 1600 kcmil) cross section copper conductors, two cables being installed simultaneously in a common trench in order to minimize direct seabed disturbance. This is the largest capacity, commercially available, solid dielectric AC cable that can be installed in two sub-sea trenches. While one manufacturer is willing to make a three-conductor cable with a higher cross section, they have indicated that it would be infeasible to install two at a time. To achieve the same capacity as the proposed interconnection, three of these larger cables would be required, each in its own sub-sea trench. In the proposed interconnection, the four cables would be grouped into two independent circuits corresponding to the two trenches (two paralleled cables per circuit). To achieve at least the same level of reliability with the three-trench configuration, three independent circuits would be required, thereby increasing the amount of terminal equipment at both the offshore and onshore substations. Likewise, the alternative of larger cross section single conductor cables would significantly increase costs, greatly complicate the logistics for installation and require more trenches, therefore increasing the potential for greater seabed disturbance.

The design of the Cape Wind submarine transmission system appears to be the best commercially available technology for this application, with the project in its proposed location. The 27 km (17 mi) length of the interconnection (17.5 km (11 mi) submarine + 9.5 km (6 mi) land), is within generally accepted limits for HVAC cables. As this cable length increases, however, the technical limitations of HVAC cable technology become more pronounced. These limitations impose technical difficulties with transmission capacity and efficiency, as well as reduced cost-effectiveness. What follows is a discussion of the reasons why distance limits the viability of HVAC cable transmission.

4.0 LIMITS ON LENGTH OF HVAC CABLES

Unlike air insulated overhead lines and HVDC insulated cable, the capacitance[2] of HVAC insulated cable plays a major role in limiting the technically and economically feasible length of HVAC cable[3]. Capacitance causes charging current to flow along the length of the cable. Because the cable must carry this current as well as the useful load current, this physical limitation reduces the load carrying capability of the cable. Because capacitance is distributed along the entire length of the cable, the longer the cable the higher the capacitance and resultant charging current. As the cable system design voltage is increased to minimize line losses and voltage drop, the charging currents also increase, thereby aggravating the situation.

The charging current is given by the formula[4]:

$$I_C = 2\pi fCE$$

where f is frequency, so that in DC circuits $I_C = 0$ in the steady state. Capacitance C is a function of cable geometry and insulation type (XLPE insulation has the lowest C value of the most commonly used alternatives for insulation in HVAC cables). E is voltage. The available capacity of the cable (ampacity) to carry useful load current I_P, in its simplest form, is given by:

$$I_P^2 = I_T^2 - I_C^2$$, where I_T = cable rated ampacity.

Because the cable capacitance is a distributed parameter, the charging current is not uniform along the length of the cable. If the charging current were supplied from one end only (to use the more exact convention, reactive power[5] would be absorbed at that end), I_C would be highest at that end and the voltage would be highest at the opposite end of the cable. These peak values of I_C and voltage become problematic for electrical reasons, hence

[2] "The property of a cable system that permits the conductor to maintain a potential across the insulation is known as capacitance" (Thue, William A. (ed), Electrical Power Cable Engineering, Marcel Dekker, 1999, p.48.)

[3] Wright, op. cit., p. 4.

[4] Thue, op. cit., p. 50.

[5] "Reactive Power: The portion of apparent power that does no work. It is commercially measured in kilovars (volt-amperes reactive). Reactive power must be supplied to most types of magnetic equipment, such as motors. It is supplied by generators or by electrostatic equipment known as capacitors." (Pansini, A.J., and Smalling, K.D., Guide to Electric Power Transmission, PennWell, 1998, p. 218.)

limiting factors in selection of the cable. If the charging current could be supplied from both ends, I_C would be highest at both ends but only half the magnitude if fed from one end only; the voltage would be highest in the middle of the cable. Whether or not the charging current can be supplied from both ends depends on system voltage conditions and the reactive capability of the WTG's.

In addition to charging currents the capacitance can also create overvoltages, high harmonic currents and undesirable resonances and may require special circuit breakers with high capacitance current switching capability, all of which further complicate the energy transfer to the electric transmission grid. In some cases power conditioning is required. These factors must be taken into account in the design of the terminal substation equipment; the longer the cable the more challenging and costly it becomes to obtain satisfactory design solutions that do not significantly disrupt or diminish transmission capacity and reliability of the overland transmission system.

Real power losses within the cable also limit the practical distance for HVAC cable transmission. Losses in an HVAC submarine cable have four components[6]:

- Dielectric losses, which are relatively small,
- I^2R Losses in the conductors, usually the largest component of losses,
- I^2R Losses in the metallic shield: current flow is induced in the shield by the current in the conductors; shield losses can be on the order of one-third of conductor losses, and
- I^2R Losses in the steel wire armor: current flow is induced in the armor by the current in the conductors; armor losses can be on the order of one-half of conductor losses.

At some length, which will vary as a function of project design, it becomes infeasible to use HVAC cable because the capacitance and/or losses are too great. A quantitative discussion appears below in Section 6.0.

5.0 ALTERNATIVES TO SOLID DIELECTRIC HVAC CABLE CONSTRUCTION

5.1 Alternative HVAC Cable Constructions

As indicated above the preferred construction technology for submarine HVAC cable is solid dielectric type. Alternative HVAC cable constructions do exist and have been available for many years in the U.S. utility industry[7,8], however these cable types are even more limited by distance than the solid dielectric type. These alternatives are:

- High-pressure pipe-type, either fluid-filled (HPFF) or gas-filled (HPGF), with paper insulation, and
- Low-pressure oil-filled (LPOF) with paper insulation, also referred to as self-contained liquid-filled (SCLF).

These cable types use lapped paper insulation impregnated with insulating oil. In the HPFF and HPGF types voids in the insulation are prevented by placing the cables in a steel pipe, then pressurizing the pipe with insulating oil or gas. In the LPOF or SCLF type the same result is accomplished by providing the conductors with a hollow core which is filled with pressurized insulating oil; no external pipe is required. Compared to XLPE, paper insulation has higher capacitance and higher dielectric losses[9] which, as discussed previously, are important limiting factors on the length of HVAC cable. Aside from this disadvantage, HPFF, HPGF and LPOF (SCLF) cables have other drawbacks. Submarine HPFF and HPGF cables cannot be direct buried using jet plow embedment methods, and must be installed by dredging excavation, first placing welded steel pipe in the sea bed and then pulling the cables through the pipe. Because of the much greater environmental impact potential and the complexity of construction in comparison to other alternatives, the need for pressurization systems and the risk of pipe rupture with the resultant environmental impacts, pipe-type submarine cables are considered unrealistic except for very short distances. Significantly greater submarine distances can be achieved with LPOF (SCLF) cables. However,

[6] Thue, op. cit., pp. 180-185. See also International Electrotechnical Commission (IEC) Standard 60287, Calculation of the Continuous Rating of Cables.
[7] Wright, op. cit., p 2.
[8] Fink, Donald G. and Beaty, H. Wayne (eds.), Standard Handbook for Electrical Engineers, 13th Edition, McGraw-Hill, 1993, pp. 14-98 – 14-101.
[9] Grainger, W. and Jenkins, N., "Offshore Wind Farm Electrical Connection Options," Proceedings of 20th BWEA Conference, Cardiff, September 1998. See also Thue, op. cit., pp. 48-49, and Fink, op. cit., p. 14-100.

they still require pressurization systems that add to cost, place practical hydraulic limits on the distance achievable and introduce the risk of environmental impact through the release of dielectric fluid should the cable rupture. LPOF (SCLF) cables have been the mainstays of AC submarine transmission for decades. However, the more modern solid dielectric cable is able to achieve greater distances, lower capital cost, lower dielectric losses and avoids potential environmental impact associated with the leakage of dielectric insulating fluid. Thus, the solid dielectric cable is rapidly replacing LPOF (SCLF) as the cable technology of choice for AC submarine cable installations[10].

5.2 HVDC Cable Construction

Because of the limitations on length of AC submarine cables, the utility industry has turned to direct current (DC) cable system technology where long transmission distances are required. Except for a brief moment upon energizing the cable, charging current and capacitive effects are not the same consideration in HVDC cables as they are in AC cable systems. Depending on voltage, line losses are on the order of 20% of equivalent AC cable losses. There are no losses in the shield or armor because, in the absence of an alternating current in the conductor, no current flow can be induced in them. Conductor losses are also lower because there is no skin effect and no reactive component of current and because only two DC conductors are required to carry the load in comparison to 3-phase / conductor AC circuits. Two types of HVDC submarine cable technology are in existence: conventional DC and the much newer voltage source converter (VSC) type. The principal difference between them is the type of AC/DC converter required at either end of the HVDC cable. Conventional HVDC submarine cable technology has been in commercial operation since 1954 and has a proven track record. It uses thyristor-based current-source converters. These converters are line-commutated, which means that they require a strong source of AC current at both ends. When there is little or no wind, this current source would not be available at the wind farm end unless provided by standby generators (probably diesel). Another disadvantage to the use of conventional HVDC technology for offshore wind farms is the size of the converter stations necessary to convert AC to DC for transmission. These converter stations can require a significant amount of surface area to contain electrical equipment and converter systems. Hence, this technology has higher costs for locating these facilities on an offshore service platform. For these reasons conventional HVDC has not been considered a viable option for offshore wind farms. The VSC-based HVDC technology uses voltage-source converters based on insulated gate bipolar transistors (IGBT). They are self-commutated and so do not need an AC current source to always be present at the wind farm[11]. Though still quite large, the converter stations are about half the size of the conventional ones. The newer VSC-based technology is being developed by ABB as HVDC Light and by Siemens as HVDC Plus. Worldwide ABB has three <u>land-based</u> HVDC Light installations in commercial operation[12]: two at ±80 kV and one at ±150 kV. The only commercial installation of ABB HVDC Light for submarine cable is the ±150 kV Cross Sound Cable, which was completed in 2002, and connects two power grids. Siemens does not yet have a commercial installation. Cross Sound's ABB HVDC Light and Siemens' HVDC Plus both utilize bipolar DC transmission consisting of two single-conductor cables operating at +150 kV and –150 kV. The Cross Sound Cable utilizes ABB's recently developed polymeric insulated DC cable. Prior to this, the choice for long DC cable systems installed in the marine environment has always been mass-impregnated paper-insulated. The insulation is essentially the same as in HPFF and LPOF types, but with no oil volume under pressure. Mass impregnated cables are not subject to leakage and are not distance limited by hydraulics. Up until now paper insulation has been preferred for DC applications because polymers tend to break down in the presence of DC fields[13]. The primary constraint to the use of HVDC for offshore wind farms is the need for the converter stations on each end of the transmission link (AC to DC offshore, DC back to AC once onshore). While losses in HVDC cable are much smaller than in HVAC, the losses in the VSC converters themselves are relatively high: 4-6% total for both ends[14]. Therefore, based on currently available technology, HVDC only becomes economically advantageous with respect to expected losses for long distances where the AC cable losses would exceed that amount. In the case of Cape Wind's proposed cable system, the AC cable losses at peak load are anticipated to be approximately 1.5% at the proposed Horseshoe Shoal location and 4.5% were the location moved 24 miles further to Nantucket Shoal. Using

[10] Wright, <u>op. cit</u>., p. 2.
[11] Grainger, <u>op.cit</u>.
[12] The first commercial VCS HVDC (DC Light) was installed on the Swedish island of Gotland in 1999. The cable is an underground, upland cable (70 km long, sized for 50 MW at ±80 kV) that connects two load centers on the island. The HVDC cable operates in parallel with an AC transmission cable, which is connected to an existing wind farm just off the island. The wind farm is connected to the HVAC cable and independent of the HVDC transmission system.
[13] Wright, <u>op. cit</u>., p. 2, and Thue, <u>op. cit</u>., p.83.
[14] Ostby, Hakon, Nexans Norway, "Power Transmission over Long Three Core Submarine AC Cables," presented at ICC Conference, Fall 2002.

manufacturer's quoted losses per km for the proposed Cape Wind HVAC cable, one can calculate that the breakeven point at which AC cable losses would equal DC cable plus converter losses is not reached until total submarine and upland cable length is approximately 100 km (62 mi).

6.0 IMPACT OF INCREASING LENGTH OF HVAC CABLE FOR CAPE WIND PROJECT

A typically cited[15] upper limit for HVAC submarine cable based on capacitance is the distance at which the cable charging current reaches the same magnitude as the useful load current ($I_C = I_P$), which corresponds to a power factor[16] of 0.7. However, detrimental impacts are encountered at distances considerably shorter than the 0.7 power factor limit, which in the case of Cape Wind would be about 75 km (47 mi). Power factors less than 0.9 are technically and economically undesirable in a transmission system or wind farm. Without compensation, the 0.9 power factor limit would be reached at a substantially shorter distance: for the state-of-the-art cable specified for Cape Wind it is about 50 km (31 mi). As the length of high voltage AC transmission cable increases, the following can be expected:

- Increased cable lengths will result in higher initial capital costs;
- Construction and maintenance costs will increase;
- Line losses will increase;
- Complexity of the design required to maintain operational reliability of the cable system would increase; and
- Amounts of available energy (MW) transmitted to the on-shore grid will decrease, due to increasing capacitance.

If lengths exceed HVAC limits, the need for HVDC converter stations will require additional on-shore acreage and offshore infrastructure at greater cost, however a portion of these costs would be offset, to a degree, by lower line losses and lower cable costs. In addition, HVDC transmissions systems have the following advantages[17]:

- Asynchronous connection, as the frequency and voltage at either end can differ,
- Avoidance of resonance between the cable capacitance and the inductive power of the grid,
- Short circuit current is not transferred, and
- Greater control of the active and reactive power.

7.0 HORSESHOE SHOAL VS. NANTUCKET SHOAL

Transmission issues figure prominently in the comparison of alternative sites for the wind farm. The proposed project location on Horseshoe Shoal would require a total length of 115kV cable of approximately 27 km (17 mi). Siting the same project on Nantucket Shoal would increase the cable length to approximately 66 km (41 mi). For purposes of comparison this cable length would be applicable for cable systems routed either around Nantucket Island, or bisecting the island. Traversing Nantucket Island with the interconnecting cable system may not reduce the overall cable route distance due to the limited nature of existing roadways available to route the cable in, possibly resulting in a circuitous route across the island. A cross-island route would be further constrained by the availability and cost of acquiring two additional landfall sites. Any direct route across the island may involve significant commercial land acquisition, traffic disruption, disturbance of undeveloped land area and sensitive or protected environmental resource areas, disturbance of cultural resource areas, and levels of environmental impacts which may impact the permitting of the entire project. Additionally, the existing electrical transmission infrastructure on the island is low voltage (25 kV) and would require upgrading to accept additional transmission capacity from a new energy source. The island's power system is presently connected to Cape Cod via a single 46 kV submarine transmission cable from Harwich to Nantucket. Due to dramatic increases in load growth on the island since 1993 and voltage level disparities, this cable is inadequate for interconnecting a new commercial

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[15] Wright, op. cit., Figure 4.

[16] The relationship among real power (MW), reactive power (MVAR) and apparent power (MVA) is vectorial and may be represented by a right triangle in which MVA is the hypotenuse and the other two sides are MW and MVAR. From trigonometry if θ is the angle between the sides representing MVA and MW, then power factor is defined as cos θ; or power factor = MW/MVA. Referring to the components of current in a cable, this is the same as saying that I_T is the hypotenuse, I_P and I_C are the other two sides, and power factor = I_P/I_T. At a power factor of 1.0 all of the apparent power is available as real power to do useful work, or one can say that the full capacity of the cable is available to carry useful load current. Thus, a power factor as close as possible to 1.0 is desirable and low power factors are undesirable.

[17] Wright, op. cit., p. 5.

scale power generation facility producing 420 MW into the New England power grid, and so a new cable would be needed.

Using HVAC technology to connect the Nantucket Shoals site to the mainland power system would require over 40 miles of cable (approximately 2.5 times the amount required for the proposed project location) and would result in significantly greater total electrical losses. Without reactive compensation the increased charging currents would also have the potential to reduce useful cable ampacity significantly. The combination of these effects in moving the location of the project to the alternative site has the potential to reduce the net peak output by an estimated 63 MW, if HVAC transmission is used. This is an approximately 15% reduction that results in an estimated net power of 357 MW delivered to NSTAR's Barnstable Switching Station, as compared to the proposed project on Horseshoe Shoal which would deliver 420 MW at peak. At the distance to Nantucket Shoals, HVDC transmission should be seriously considered, once it is commercially proven for offshore wind applications. Greater cost for the converter stations at both ends of the transmission line is offset by lower cable costs and lower line losses than HVAC, but these are only realized at longer distances. While there will be significant line losses from the Nantucket Shoals site using HVAC, the distance from the site to landfall on Cape Cod is still less than the calculated l00 km (62 mi) breakpoint where DC and AC losses are equal. Electrical losses for HVAC would be less than losses using HVDC for the approximately 41 mile interconnection from Nantucket Shoals.

Tables 3-C.1 and 3-C.2 detail the basic engineering components and approximate costs associated with both HVAC and HVDC interconnection options from Nantucket Shoals. Both options result in substantially greater electrical losses and higher costs than the proposed HVAC interconnection from Horseshoe Shoal.

8.0 COMMERCIAL AVAILABILITY

HVAC transmission systems are widely available and have a robust track record. Conventional HVDC transmission has also been in use for nearly 50 years, and has been successfully utilized for long distance submarine applications, such as 250km crossings of the Baltic Sea, and most recently across Long Island Sound. As noted above, AC transmission has been used for all wind power projects to date. For example, there is a five WTG installation (total 2.5 MW) just off the island of Gotland in Sweden. Although there is a 70 km (43 mi) HVDC Light underground cable (50 MW at ±80kV) connecting two load centers on the island, the offshore wind project uses a conventional submarine AC cable which is connected to the island's AC system. The two leading manufacturers of newer voltage source converter (VSC) HVDC systems, ABB and Siemens, have great promise for the future, but have not yet developed HVDC systems for the unique requirements of offshore wind generation. As such, HVDC does not yet have a track record and cannot be considered commercially available.

9.0 CONCLUSION

While there are clear advantages to emerging HVDC transmission technologies, particularly at longer distances, the proven and most cost effective presently available cable transmission technology for connecting near shore wind farms (< 50 – 100 km) to onshore utility transmission systems is solid dielectric HVAC submarine cable systems. The capacitance and losses limit the technically feasible length of HVAC cable and can have significant economic impacts on project viability even at moderate distances. The new VSC based HVDC technology shows potential as a future alternative to HVAC for high voltage at longer distances; however, it has not yet been proven to be a commercially available technology for offshore wind farms.

Table 3-C.1: Nantucket Shoal to Barnstable Switching Station – AC Option

Item No.	Item Description	Units	Quantity	Unit Material Cost	Unit Installation Cost	Extended Material Cost	Extended Installation Cost	Total Installed Cost	Remarks	Source
1	115 kV AC Submarine cable	miles	35.0	2,500,000	1,200,000	87,500,000	42,000,000	$129,500,000	four 3/C cables; landfall 500 ft HDD included	unit prices extracted from Pirelli-ABB proposal for Horshoe Shoal
2	115 kV AC upland cable in streets	miles	4.0	2,300,000	1,100,000	9,200,000	4,400,000	$13,600,000	1/C 800mm2 x 12 (2 ckts x 2 cond per phase x 3 phase)	unit prices extracted from Pirelli-ABB and Nexans proposals for Horshoe Shoal
3	Upland civil costs in streets	miles	4.0		1,500,000	-	6,000,000	$6,000,000	in ductbank 8 x 2, >4.5 ft deep, concrete encased; material costs included	engineering cost opinion; agrees with EFSB Petition Table 4-4
4	115 kV AC upland cable in Nstar ROW	miles	1.9	1,700,000	800,000	3,230,000	1,520,000	$4,750,000	1/C 630mm2 x 12 (2 ckts x 2 cond per phase x 3 phase)	unit prices extracted from Pirelli-ABB and Nexans proposals for Horshoe Shoal
5	Upland civil costs in Nstar ROW	miles	1.9		1,000,000	-	1,900,000	$1,900,000	in ductbank 8 x 2, min depth, concrete encased; material costs included	engineering cost opinion; agrees with EFSB Petition Table 4-4
6	Offshore Substation Elec Eqpmt	lot	1	12,000,000		12,000,000		$12,000,000	excludes 33 kV switchgear & platform structure; equipment installation included	engineering cost opinion
7	150 MVAR shunt reactors	reactor	2	1,300,000	500,000	2,600,000	1,000,000	$3,600,000	located at Barnstable S/S; SVC if required would be much costlier	extrapolation from previous Nstar project
							Total	$171,350,000		

Notes: 1. Only items not common to AC and DC options are included

Table 3-C.2: Nantucket Shoal to Barnstable Switching Station – DC Option

Item No.	Item Description	Units	Quantity	Unit Material Cost	Unit Installation Cost	Extended Material Cost	Extended Installation Cost	Total Installed Cost	Remarks	Source
1	+/-150 kV DC Submarine cable	miles	35.0	750,000	375,000	26,250,000	13,125,000	$39,375,000	four 1/C 630 mm2 cables; landfall 500 ft HDD included	unit material and labor costs derived from ABB email 4 July 03 and subsequent telecon 8 July 03
2	+/-150 kV DC cable in streets	miles	4.0	750,000	375,000	3,000,000	1,500,000	$4,500,000	four 1/C 800 mm2 cables	material cost taken as 4/12 AC upland cable cost for same cross section single conductor; installation taken as 50% of material cost based on comparable pricing in proposals for single conductor upland AC cable
3	Upland civil costs in streets	miles	4.0		1,300,000	-	5,200,000	$5,200,000	in ductbank 4 x 2, >4.5 ft deep, concrete encased; material costs included	engineering cost opinion
4	+/-150 kV DC cable in Nstar ROW	miles	1.9	600,000	300,000	1,140,000	570,000	$1,710,000	four 1/C 630 mm2 cables	material cost taken as 4/12 AC upland cable cost for same cross section single conductor; installation taken as 50% of material cost based on comparable pricing in proposals for single conductor upland AC cable
5	Upland civil costs in Nstar ROW	miles	1.9		800,000	-	1,520,000	$1,520,000	in ductbank 4 x 2, min depth, concrete encased; material costs included	engineering cost opinion
6	AC/DC Converter Stations	pair	2	62,000,000		124,000,000		$124,000,000	excludes 33 kV switchgear & platform structure; equipment installation included	Siemens email 2 Aug 02
7	Increased size of the Offshore Electrical Service Platform	lot	1	13,500,000		13,500,000		$13,500,000	Larger superstructure to accommodate the larger AC/DC converter station	Engineering cost opinion
8	Land Acquisition	acres	3.5	159,000		556,500		$556,500	Land for converter station adjacent to Barnstable S/S (if available)	Barnstable Count Assessor's data
								Total $190,361,500		
	Notes:									
	1. Only items not common to AC and DC options are included									
	2. This comparison assumes onshore DC converter station would be located at Barnstable Switching Station.									